TUSK ENERGY INC.

2000 Annual Report

Corporate Profile

TUSK Energy Inc. is a public company engaged in the exploration for, development and production of oil and gas in Western Canada. The common shares of the Company trade on The Toronto Stock Exchange (Symbol: TKE). TUSK is a reporting issuer in the provinces of Ontario, Saskatchewan, Alberta and British Columbia.

The major assets of the Company are its interests at Saddle Lake and Whitefish Lake, Alberta (natural gas exploration/development and production), Meekwap, Alberta (light oil and natural gas production and development), Strachan, Alberta (natural gas exploration/development and production) and Silverdale and Epping, Saskatchewan (heavy oil development). The Company also has light oil production at various Alberta locations (Progress, Spirit River, Leduc and Willesden Green) and gas production at Gilby, Lacombe and Carvel. The exploration programs of the Company concentrate on natural gas prospects. TUSK is currently operating more than 75% of its production and most of its exploration prospects.

Stockholder Information

As of December 31, 2000 the number of common shares outstanding was 14,599,430. The Annual Meeting of TUSK Energy Inc. will be held at 2:00 p.m. Calgary time on Tuesday, May 29, 2001 at The 400 Club, 710 - 4th Avenue S.W., Calgary, Alberta.

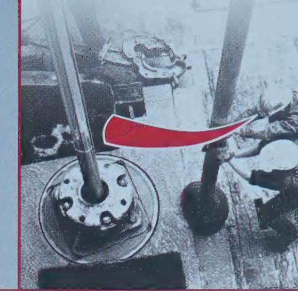
Contents

Abbreviation Table

Bbls	barrels of oil
Bopd	barrels of oil per day
Bpd	barrels per day
BOE	barrels of oil equivalent
Boepd	barrels of oil equivalent per day
Mbbls	thousands of barrels
MBOE	thousands of barrels of oil equivalent
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day
MMcf	million cubic feet
MMcfd	million cubic feet per day
Mstb	thousand stock tank barrels
NGL's	natural gas liquids

1 barrel of oil = 0.15891 cubic metres
1 Mcf of gas = 28.17399 cubic metres
1 barrel of oil equivalent = 10 Mcf gas

To reflect industry trends with regard to the reporting of barrels of oil equivalent two cases are presented in this report. These are 10 Mcf = 1 BOE and 6 Mcf = 1 BOE. If not otherwise indicated, the conversion used is 6 Mcf = 1 BOE



Highlights

Financial

Financial	Quarter Ended December 31 2000	Year Ended December 31 2000	Year Ended December 31 1999	Year Ended Percentage Change
Revenue (Net of Royalties)	**$ 2,078,932**	$ 6,805,788	$ 5,086,350	34%
Net Income	**$ 287,204**	$ 908,592	$ 990,406	(8%)
Per Share	**$ 0.02**	$ 0.06	$ 0.08	(25%)
Cash Flow From Operations	**$ 1,197,404**	$ 3,544,892	$ 2,418,606	47%
Per Share	**$ 0.08**	$ 0.25	$ 0.20	25%
Working Capital (Deficiency)		$ (2,223,265)	$ (44,859)	–
Total Assets		$ 33,062,958	$ 17,199,428	92%
Long-Term Debt		$ 4,350,000	$ 3,900,000	12%
Weighted Average Common Shares		14,225,941	11,959,976	19%
Net Debt to Cash Flow Ratio	**1.15**	1.62	1.63	0%

Operating

Operating	Quarter Ended December 31 2000	Year Ended December 31 2000	Year Ended December 31 1999	Year Ended Percentage Change
Production				
Oil & NGL's (bpd)	**511**	475	562	(15%)
Gas (Mcfd)	**1,700**	1,417	1,036	37%
Boepd (10:1)	**688**	616	666	(8%)
Boepd (6:1)	**806**	711	735	(3%)
Reserves (proven plus 50% probable)				
Oil & NGL's (Mbbls)		2,204	2,967	(26%)
Gas (MMcf)		14,448	14,645	(1%)
BOE (10:1)		3,649	4,432	(18%)
BOE (6:1)		4,612	5,408	(15%)
Land Holdings (Canada)				
Gross Acres		224,985	128,521	75%
Net Acres		85,540	43,845	95%

Message to Shareholders

The year 2000 marked a watershed for TUSK. TUSK laid a foundation for future growth by substantially increasing our undeveloped land position and rationalizing existing assets. Fueled by expansion of our drilling efforts, discoveries of new oil and gas reserves and commodity prices annualized cash flow per share grew from $0.18 in the second quarter to $0.25 in Q3 and $0.32 in Q4. The momentum has continued into 2001 with the impact of our Q4 drilling program coming in the second quarter of 2001 as new gas wells start production.

Achievements during 2000 include the following:

- drilled 21 wells – more than double the previous year;
- drilling success rate of more than 70% on a net basis (100% on First Nations lands);
- acquired Auburn Energy to gain access to 105 sections of First Nations lands for exploration and development;
- expanded exploration group;
- negotiated the sale of a part of the Meekwap property;
- consistent growth in cash flow and asset per share;
- exited 2000 fiscal year with strong balance sheet.

Our growth strategy, which emphasized gas exploration, risk reduction and acquisitions, has been effective. The joint venture on the Saddle Lake and Whitefish Lake First Nations has led to successful gas exploration, highlighting the gas emphasis of the Company. The gas reservoirs on the joint venture lands occur at shallow depths and require relatively minimal expenditures for exploration and development. During 2001 TUSK will continue to focus on balance and diversification in an effort to provide the best return for the shareholders while keeping both exploration/development and financial risk exposure at acceptable levels.

Growth is occurring through the shift towards properties with less financial and drilling risk, the increase in our natural gas exposure and the large amounts of exploration and development lands acquired under our First Nations ventures. While this document reports on the financial and operating results for the 2000 fiscal year, considerable space is devoted to discussion of our First Nations projects, and their potential impact.

Balance & Diversification

The Auburn acquisition of May 2000 has yielded a significant return for TUSK. After investment of $5.2 million in cash and shares for the purchase and $0.95 million in capital expenditures to year-end, TUSK has an asset worth approximately $10.4 million. Acquisitions continue to be an important element of our growth strategy.

The First Nations joint ventures have been very successful. The first of these is with Keyano Pimee Exploration Company Ltd. (wholly-owned by the Saddle Lake and Whitefish Lake First Nations). TUSK/Keyano drilled four wells and re-completed another in 2000. Our success rate has been 100%. Drilling on our second joint venture, with the Alexis First Nation, will commence in 2001.

Reflecting the success of our First Nations ventures, TUSK made a bid on March 30 to acquire all of the shares of Spirit Energy Ltd., a private Alberta company. Spirit is a partner with TUSK in all three First Nations. The acquisition, expected to close in late April, increases the interests of TUSK at Saddle Lake, Whitefish Lake and Alexis by 25%.

Key objectives during 2000 were met. A record number of wells were drilled and our cash flow per share increased steadily. During 2001, we will continue with an active drilling program concentrating on low to medium risk gas prospects.

Issuer bid – TUSK purchased for cancellation 1,400,000 common shares in the 2000 fiscal year and has purchased another 691,500 common shares during the first quarter of 2001. As of the end of Q1 – 2001 the Company has 13,907,930 common shares outstanding.

The commitment of management to the future of TUSK was demonstrated during Q2 – 2000 when the management and directors purchased 1,125,000 common shares in a market trade at $0.85 per common share. The success of the past year would not have been possible without the commitment of our employees, the leadership of our management team and the guidance provided by our directors. The contributions of all of them are appreciated.

Consistent Growth in Cash Flow Per Share

A solid foundation for future growth has been established in 2000 through the acquisition of Auburn, the signing of a joint venture arrangement with the Alexis First Nation and the sale of a portion of our Meekwap property effective as of the year-end. TUSK has prospective lands to exploit and the financial ability to develop them.

The effectiveness of this strategy will become apparent in the second and third quarters of 2001, when the full impact of our 2000 and first quarter of 2001 drilling on the Saddle Lake First Nation will become apparent. In fact, our first quarter 2001 production will be negatively impacted by the year end sale of a part of our Meekwap interest and normal declines as TUSK awaits the completion of production facilities at Saddle Lake. However, TUSK expects, beginning in the second quarter, to demonstrate consistent growth in production as it continues to develop its First Nations permits and its inventory of exploratory prospects elsewhere in Alberta.

Norman W. Holton
President and Chief Executive Officer
April 9, 2001

Exploration & Operations Review

Highlights

- acquired Auburn Energy and its joint venture with Saddle Lake and Whitefish Lake First Nations;
- drilled four gas discoveries at Saddle Lake;
- arranged joint venture with Alexis First Nation;
- developed heavy oil production at Silverdale, Saskatchewan;
- sold shut-in gas wells and interest in exploration play in northeastern British Columbia for profit;
- arranged sale of a portion of the Meekwap property.

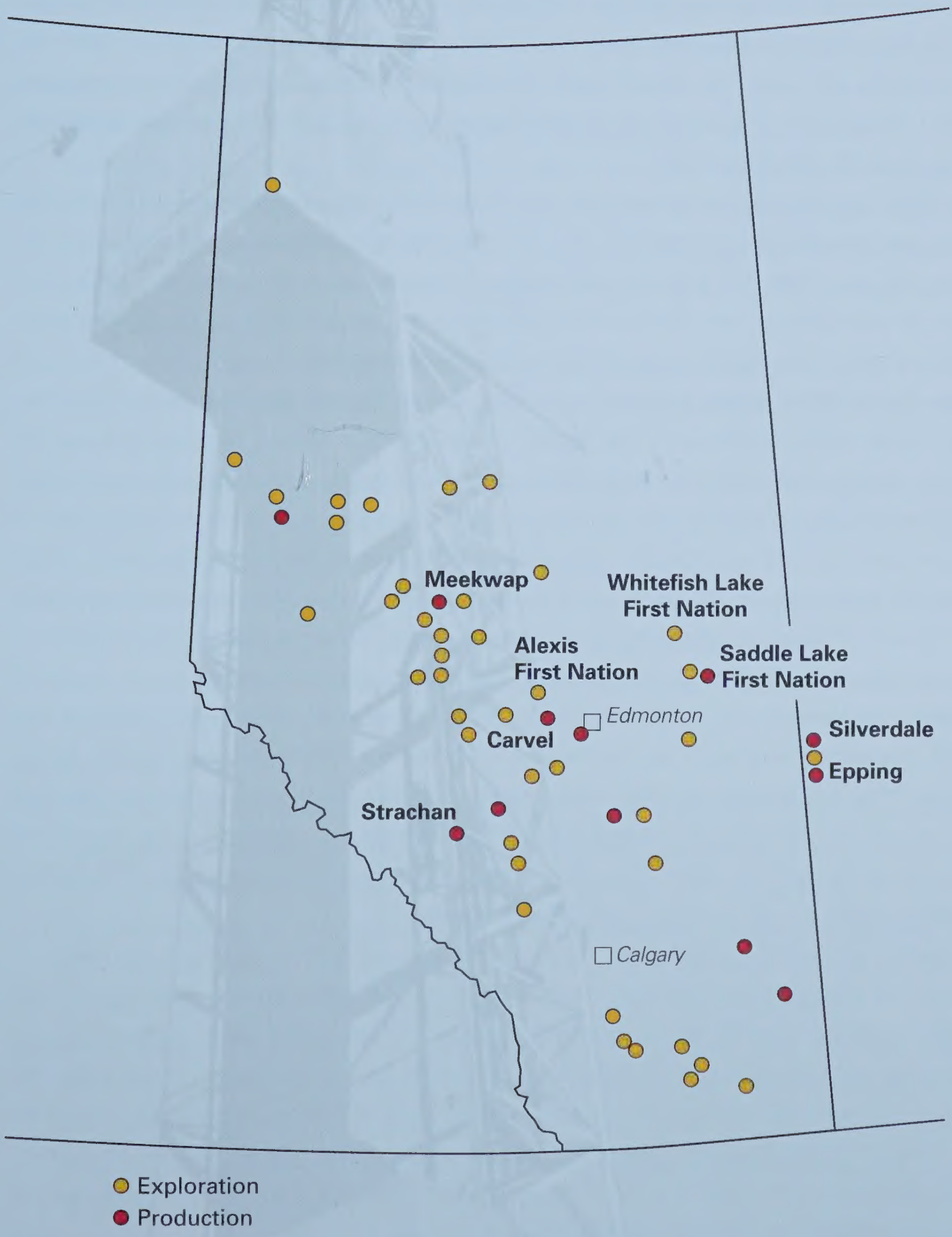
Exploration & Land

During the year TUSK participated in the drilling of a total of 21 wells, resulting in 6 gross oil (1.85 net), 7 gross gas (2.31 net), 1 gross (0.50 net) service well and 7 gross dry holes (1.69 net) as shown below. Nine of the wells were operated by TUSK or its wholly-owned subsidiary Auburn Energy Ltd.

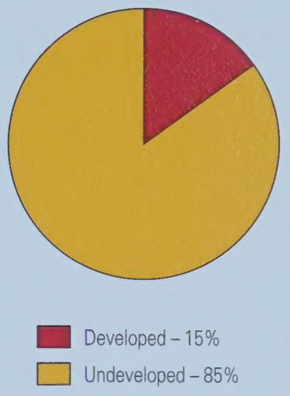
Property	Operator	Interest (%)	Result
Dawson	TUSK	50	dry
Saddle Lake	Auburn	40	gas
Silverdale	3rd party	50	oil
Silverdale	3rd party	50	oil
Spirit River	3rd party	1	dry
Ranfurly	3rd party	GORR	dry
Cyn-Pem	3rd party	GORR	dry
Strachan	3rd Party	33	gas
Meekwap	TUSK	16	dry
Meekwap East	TUSK	33	oil
Saddle Lake	Auburn	40	gas
Saddle Lake	Auburn	40	gas
Saddle Lake	Auburn	40	gas
Spirit River	3rd party	GORR	oil
Forty Mile	TUSK	37	gas
Silverdale	3rd party	50	oil
Silverdale	3rd party	50	service
Spirit River	3rd party	1	dry
Lacombe	TUSK	100	dry
Spirit River	3rd party	1	oil
Cremona	3rd party	GORR	gas

Prospects are Weighted to Natural Gas

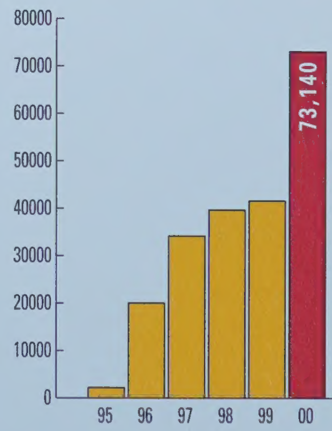
TUSK Operation Areas



2000 Net Acreage



Undeveloped Land
(net acres)



Property Review

Saddle Lake First Nation & Whitefish Lake First Nation, Alberta

Saddle Lake and Whitefish Lake will become the most significant property for TUSK. Production from these areas represented an average of 14% of total corporate production during the year and increased to 21% of our production at year-end. This trend is expected to continue.

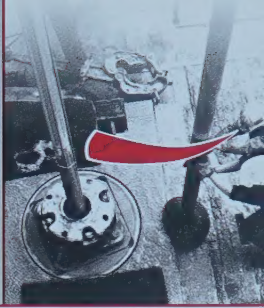
The Saddle Lake and Whitefish Lake properties are located approximately 130 kilometres (80 miles) to the northeast of the City of Edmonton near the Town of St. Paul. As of the end of the fiscal year, the Company has a 40% working interest in 10 producing gas wells and three shut-in gas wells. The shut-in wells were drilled or re-completed in the fourth quarter of 2000 will be tied-in prior to the end of April. The lands are contained in three permits (59,520 gross acres, 23,800 net acres).

History: TUSK acquired Auburn Energy Ltd. and its joint venture arrangement with the Saddle Lake and Whitefish Lake First Nations, which included interests in seven producing gas wells, in May 2000. All of these wells were drilled and/or re-completed through a joint venture arrangement with Keyano Pimee Exploration Company Ltd., a private company wholly-owned by the Saddle Lake and Whitefish Lake First Nations.

Activities During 2001: Three additional gas wells, two at Saddle Lake and one at Whitefish Lake were drilled in February. The Saddle Lake wells will be tied-in during the second quarter and the Whitefish Lake well will be tied-in later in the year. A seismic survey, shot at Whitefish Lake during the first quarter, will be evaluated in April 2001. A compressor is currently being installed at Saddle Lake which will allow all of the Saddle Lake wells drilled over the past year to be tied-in to a Company operated facility without third party restrictions on levels of production. In late March, TUSK moved to increase its interests at Saddle Lake and Whitefish Lake by bidding to takeover a private company.

Production: Net production to TUSK, from the Saddle Lake properties, averaged 620 Mcfd during 2000. December average production was 1,064 Mcfd net. Wells drilled during the fourth quarter 2000 and first quarter 2001 will be tied-in by the end of the second quarter. Much of the natural gas produced at Saddle Lake will flow through a compressor to be operational approximately April 20, 2001. Two Nova lines run through the Saddle Lake First Nation providing ready access to markets for Saddle Lake gas.

Saddle Lake: Approximately 60% of the sections surrounding Saddle Lake have gas wells on them. We anticipate that the joint venture lands will contain a similar proportion of gas wells. There are 14 wells on the joint venture lands at Saddle Lake either producing gas or being tied-in by the end of the second quarter. Drilling and re-completion efforts at Saddle Lake have been very successful. The joint venture lands at Saddle Lake include more than 40 sections which have not been evaluated as of the present time. Review of seismic, both purchased and shot by the Company, indicates a number of additional drilling locations. Additional shooting is anticipated later in 2001.



Whitefish Lake: The Company currently has two wells capable of gas production at Whitefish. Seismic and drilling will commence in the first quarter of 2001.

Outlook: The Saddle Lake and Whitefish Lake First Nations provide a substantial amount of acreage with numerous opportunities for low risk drilling. The multiple natural gas targets occur at relatively shallow depths of 750 metres or less. Up to 15 wells may be drilled on these properties during 2001 with a similar amount planned for the following year. The Company's ongoing program here has already led to an effective doubling of the gas reserves since the property was acquired during the second quarter of 2000.

Alexis First Nation, Alberta

The Alexis First Nation is located approximately 36 miles to the northwest of the City of Edmonton near Glenevis, Alberta. The Company has a 30% interest (to increase to 37.5% when the Spirit acquisition is completed) in a 25 section permit granted under a joint venture arrangement with Alexis Oil & Gas Corp. ("Alexis"), a private company wholly-owned by the Alexis First Nation. Keyano Pimee Exploration Company Ltd. (12.5%) participates with the Company as an industry partner.

History: The joint venture agreement with Alexis was signed in June 2000. Under the terms of the joint venture, the Company was required to drill an initial well prior to May 2001. No wells were drilled during 2000.

Activities During 2000: Geological analysis was completed during the third quarter and prior to the end of the year the Company conducted a seismic survey on the property, evaluated it and determined a location for the initial earning well.

Activities During 2001: The initial earning well will be drilled in April. In late March, TUSK moved to increase its interests at Alexis by bidding to takeover a private company.

Outlook: Assuming that the initial well yields a favourable result, additional drilling is anticipated for later in 2001.

Meekwap, Alberta

The Meekwap property represented 55% of TUSK's gross production during the 2000 fiscal year. The Company's interests included, during 2000, a 16.9% working interest in the Meekwap D-2A Unit and various interests in 8,320 gross acres (13 sections) of surrounding lands. In January 2001 the Company closed the sale of a portion of its interests at Meekwap reducing its Unit ownership to 10% and its stake in the adjacent lands by 50% as of December 31, 2000. Effective March 1, 2001 TUSK ceased being the operator of these properties.

Activities During 2000: TUSK drilled two wells in the Meekwap area. The first (33% net), drilled to the east of the Unit during the third quarter, has been cased as a potential oilwell. The second (16% net) was drilled in the Unit in the fourth quarter and was abandoned. Note that these working interests have now been decreased as a consequence of the sale referenced above.

Activities During 2001: A Unit infill well has been approved for drilling and is expected to be drilled during the second quarter of 2001.

Strachan, Alberta

The Strachan property is located in west-central Alberta approximately 145 kilometres northwest of the City of Calgary. TUSK owns working interests of 25% to 60% in a total of 28 contiguous sections or 17,280 gross acres (5,648 net). Average working interest in the lands is more than 31%.

Activities During 2000: Production from the Slave Point reservoir in the 2-22 well averaged 338 MMcfd of raw gas (184 MMcfd of sales gas) during the year. TUSK has a 10% before payout and a 30% after payout interest in the well. Production was interrupted frequently during the year due to repairs to a casing leak. This problem now appears to be resolved. The Slave Point produces from a depth of 4,300 metres.

A well (3,100 metres) was drilled during the fourth quarter at 12-23 (TUSK 33% net) to evaluate the potential of some of the shallower horizons. While the well tested minor amounts of gas from two zones it has been disappointing. It may be tied-in during the third quarter of 2001 if gas prices stay high.

Activities During 2001: All of the Company's 41 square kilometres of 3-D seismic coverage over these lands has been re-evaluated and a number of possible drilling targets have been identified. Discussions will occur shortly with the partner group to determine a course of action. A minor workover of the 2-22 well in February 2001 has led to a production increase to approximately 2,800 MMcfd of raw gas.

Outlook: The discovery of deep gas at Strachan is very encouraging and the consistent level of production from the 2-22 well suggests the possibility of significant areal extent for the reservoir.

Seismic interpretation looks encouraging but further development of the prospect will be expensive. Accordingly, a portion of the TUSK interest will likely be farmed out prior to additional drilling in this area.

Silverdale/Saskatchewan

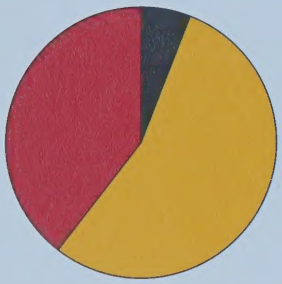
TUSK owns a 50% working interest in 160 acres of land in this area approximately five miles south of the City of Lloydminster. The first well on this prospect was an oil discovery drilled in December 1999.

Activities During 2000: The initial discovery was put on production in February 2000. A 3-D seismic survey, shot during the second quarter, helped to define additional drilling locations. Two development wells, both oil discoveries, were drilled in July and two more wells (one oil and one cased as a service well) were drilled in November.

Production: Production during the year averaged 53 Bopd gross (26 Bopd net). As of the end of the year the production rate, with four wells producing, was 64 Bopd gross (32 Bopd net).

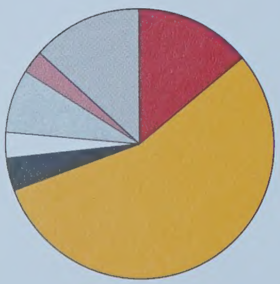
Outlook: Potential exists for several additional locations based upon 3-D seismic. A decision on further drilling will be made later in 2001.

Production Summary

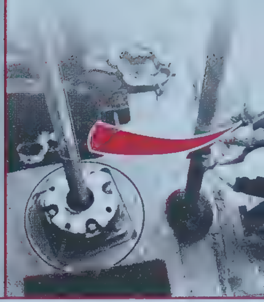


Medium/Heavy Oil – 5.9%
Light Oil – 54.6%
Gas – 39.5%

Production



Saddle Lake – 13.9%
Meekwap – 55.4%
Carvel – 3.9%
Willesden Green – 3.1%
Strachan – 7.6%
Gilby – 2.8%
Other – 13.3%



Epping, Saskatchewan

TUSK owns a 50% working interest in 600 acres of land in this area approximately 21 miles south of the City of Lloydminster. The only well drilled to date was drilled in the fourth quarter of 1999 and placed on production in February 2000. Additional drilling is expected during the latter part of 2001 once seismic has been reviewed and production streamlined.

Other Properties

During the year, TUSK drilled a 100% shallow gas discovery at Lacombe. The well currently produces 180 Mcfd. During the fourth quarter the Company drilled a gas discovery (37% net) at Forty-Mile Coulee, in southern Alberta. Production alternatives are currently being evaluated.

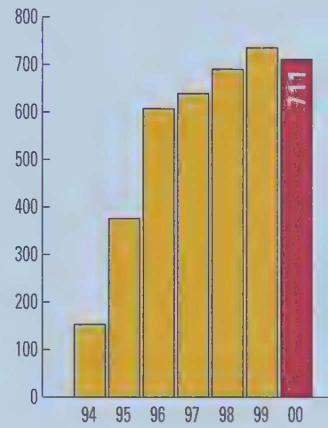
The exploration activities of the Company are focused in Alberta, primarily on natural gas prospects at medium to shallow depths. The Company participated in 10 wells in 1999 and 21 in 2000. This growth trend is expected to continue during 2001 with a participation target of 40 wells.

Production

Virtually all of the Company's production comes from five areas in Alberta with over 55% of total production being derived from the Meekwap Unit and Meekwap East Flank lands. The most significant growth area for TUSK was Saddle Lake increased from zero to 14% of our BOE production (10:1) (19% @ 6:1) at the end of the fiscal year. The Company owns interests in one minor oil producing property in Saskatchewan and two heavy oil properties at Silverdale and Epping in Saskatchewan which were put on production in February 2000. Gas production, which represented 39.5% of total BOE production, is primarily from Saddle Lake with lesser amounts from Carvel, Strachan and Meekwap.

Production has grown steadily over the past several years as shown by the production graph. Average production for the year was 511 Bopd and 1,770 Mcfd (711 Boepd), a 3% decrease over the production levels of 1999 with a 37% increase in gas production.

Average Daily Production
(Boepd @ 6:1)



Reserves and Future Net Revenue

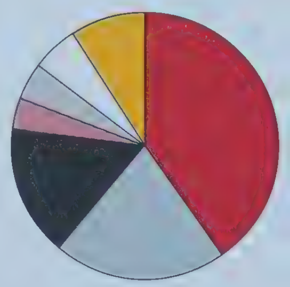
TUSK's reserves were evaluated at January 1, 2001 by Chapman Petroleum Engineering Ltd. an independent reservoir engineering firm.

Crude oil and NGL reserves decreased 26% from 2,967 Mbbls to 2,204 Mbbls and natural gas reserves decreased 1% from 14,645 MMcf to 14,448 MMcf. Reserve decreases reflect the sale of shut-in gas reserves in northeast British Columbia effective January 1, 2000 and the sale of various interests at Meekwap effective December 31, 2000. Offsetting these sales was the discovery of 3,333 MMcf of gas, mainly at Saddle Lake, Strachan and Forty-Mile Coulee. These reserves are gross proven and probable reserves (risked at 50%), net of production and revisions to prior years estimates.

The present worth value before income taxes of the proven plus probable reserves (risked at 50%) at 15% discount factor is $40,175,000.

These values were based on escalated price and cost assumptions as estimated by Chapman Petroleum Engineering Ltd.

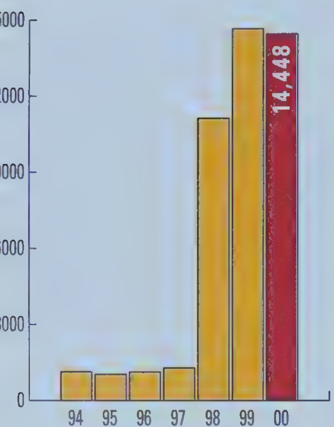
Reserves Value
(Proven + 50% Probable)



Meekwap – 40.2%
Strachan – 20.9%
Saddle Lake – 15.9%
Silverdale – 3.8%
Howard/Hartaven – 4.5%
ARTC – 5.6%
Other – 9.1%

Estimates Reserves of Crude Oil and Natural Gas based on Escalated Pricing and Cost Assumptions at January 1, 2001

Gas Reserves
Proved & 50% Risked Probables
(MMcf)



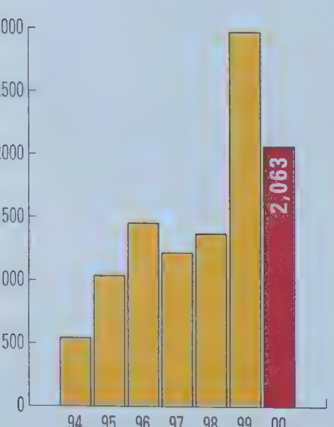
	Crude Oil & NGL's (Mbbls)		Natural Gas (MMcf)	
	Gross	Net	Gross	Net
Proved Developed Producing	849	672	4,115	3,192
Proved Developed Non-Producing	110	87	3,435	2,545
Proven Undeveloped	733	566	1,159	968
Total Proven	1,692	1,325	8,709	6,705
Probable (risked at 50%)	512	355	5,739	3,881
Total Established Reserves	**2,204**	**1,680**	**14,448**	**10,586**

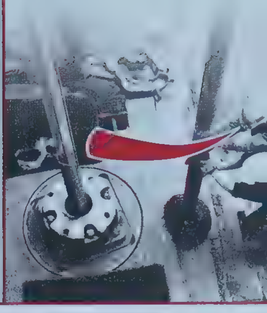
Gross reserves are the Company's share of reserves and net reserves are gross reserves after deduction for crown, freehold and other royalties.

Discounted Value of Estimated Future Net Revenue before Income Taxes based on Escalated Price and Cost Assumptions at January 1, 2001

		Discounted at		
	Undiscounted	10%	15%	20%
Proven Developed Producing	$ 27,676	$ 18,417	$ 15,892	$ 14,044
Proven Developed Non-Producing	12,197	6,916	5,178	4,889
Proven Undeveloped	16,002	10,757	9,126	7,870
Total Proven	55,875	36,090	30,736	26,803
Probable (50%)	22,107	11,870	9,439	7,752
Total Established Reserves	**$ 77,982**	**$ 47,960**	**$ 40,175**	**$ 34,555**

Oil Reserves
Proved & 50% Risked Probables
(Mstb)





Reserve Reconciliation (Before Royalties)

The following table provides the changes in TUSK's gross reserves based on escalated price and cost assumptions since January 1, 2000.

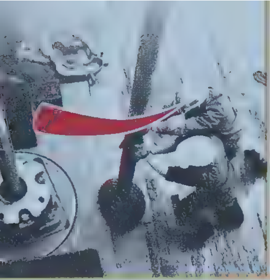
	Proven			Proven and 50% of Probables		
	Crude Oil & NGL's (Mbbls)	Natural Gas (MMcf)	MBOE (6:1)	Crude Oil & NGL's (Mbbls) (6:1)	Natural Gas (MMcf)	MBOE
January 1, 2000	2,448.0	7,491.0	3,696.5	2,967.0	14,645.0	5,407.8
Production	(173.4)	(517.3)	(259.6)	(173.4)	(517.3)	(259.6)
Discoveries	–	3,333.0	555.5	–	3,373.5	562.3
Purchases	222.4	1,891.3	537.6	259.4	1,948.8	584.2
Divestitures	(808.7)	(1,941.5)	(1,132.3)	(861.5)	(1,965.8)	(1,189.1)
Adjustments	3.7	(1,547.5)	(254.2)	12	(3,036.7)	(494.1)
December 31, 2000	1,692.0	8,709.0	3,143.5	2,203.5	14,447.5	4,611.4

Reserve Life Index (Years)

December 31, 2000	Proven	Proven & 50% of Probables
Crude Oil & NGL's	9.8	12.7
Natural Gas	16.8	27.9

Reserve Replacement Ratio

December 31, 2000	Proven	Proven & 50% of Probables
Crude Oil & NGL's	–	–
Natural Gas	6.4	6.5
BOE's (6:1)	2.1	2.2
BOE's (10:1)	1.3	1.5



Finding and On-Stream Costs

	Year Ended December 31 2000	Year Ended December 31 1999	Year Ended December 31 1998
	($)	($)	($)
Finding Costs			
Land	1,151,365	494,518	807,132
Seismic & Other Exploration Costs	1,454,085	1,277,498	130,759
Drilling & Completion	3,233,530	2,192,201	2,704,152
Total	5,838,980	3,964,217	3,642,043
Well Equipment & Production Facilities	696,365	490,066	588,348
Total	6,535,345	4,454,283	4,230,391
Costs Per BOE (6:1)			
Finding			
Proven	10.51	2.65	4.18
Proven Plus 1/2 Probable	10.39	2.09	1.71
On-Stream			
Proven	11.76	2.99	4.86
Proven Plus 1/2 Probable	11.62	2.35	1.98
Costs Per BOE (10:1)			
Finding*			
Proven	17.52	3.05	5.58
Proven Plus 1/2 Probable	17.31	2.34	2.48
On-Stream*			
Proven	19.61	3.43	6.48
Proven Plus 1/2 Probable	19.37	2.63	2.88

* Finding and on-stream costs increased significantly in 2000, mainly due to our increased exploration focus with dramatic increases in our undeveloped land base (from 41,635 net acres in 1999 to 73,140 net acres in 2000) and seismic and other exploration costs which have resulted in successful wells in the first quarter of 2001 and will continue to see results throughout 2001 and beyond.

Asset Value Per Common Share

December 31, 2000 ($ except Share Information)	
Assets	
Working Capital (Deficiency)	(2,223,265)
Proved and Probable Reserves (Risked at 50%) – (Escalated Pricing) (per Chapman Petroleum Engineering Ltd. Reserve Report @ 15% DCF)	
Established Reserves	40,175,000
Undeveloped Land (73,140 net acres @ $75/Acre)	5,485,500
Other Assets, Net	1,162,757
	44,599,992
Liabilities	
Long-Term Debt	(4,350,000)
Future Income Taxes	(5,912,249)
Future Site Restoration Provision	(283,062)
Net Asset Value	$ 34,054,681
Common Shares Outstanding December 31, 2000	14,599,430
Net Asset Value Per Common Share	$ 2.33

Summary of Information Per BOE

	Year Ended December 31 2000 ($)	Year Ended December 31 1999 ($)
Gross Revenue	34.76	22.11
Royalties, Net of ARTC	8.55	3.13
Net Revenue	26.21	18.98
Operating Expense	7.87	5.76
Net Operating Revenue	18.34	13.22
General & Administrative	2.65	2.51
Loss on Foreign Exchange	–	0.65
Interest Expense	1.88	1.03
Current Income Taxes	0.16	–
Cash Flow Per BOE (6:1)	13.65	9.03
Cash Flow Per BOE (10:1)	15.74	9.96

Management's Financial Analysis and Discussion

The following discussion is presented in conjunction with the consolidated financial statements and accompanying notes.

Oil and Gas Revenues

Oil and gas revenue, before royalties, for the year ended December 31, 2000 was $9,025,205 compared to $5,925,901 for the year ended December 31, 1999, a 52% increase. This was due to a $10.05 per barrel increase in the average oil price and a $3.45/Mcf increase in the price of gas in 2000, offset in part with a 3% decrease in BOE production from 268,018 BOE to 259,643 BOE.

Oil and Gas Sales

	Year Ended December 31 2000	Year Ended December 31 1999
Oil & Gas Revenues, Before Royalties	$ 9,025,205	$ 5,925,901
Oil Production (Bbls)	173,426	205,018
Oil Price ($/Bbl)	$ 32.11	$ 22.06
Gas Production (MMcf)	517	378
Gas Price ($/Mcf)	$ 6.27	$ 2.82
BOE Production (10:1)	225,156	242,835
BOE Production (6:1)	259,643	268,018
BOE per Day (10:1)	617	666
BOE per Day (6:1)	711	734

Royalties

The total royalties, net of Alberta Royalty Tax Credit (ARTC) were $2,219,415 ($8.54 per BOE) for the year ended December 31, 2000 compared to $839,551 ($3.13 per BOE) for the year ended December 31, 1999.

Higher product prices, which result in higher provincial royalty rates and higher provincial royalties, was the main reason for the higher royalties per barrel. In addition, the ARTC rate averaged 25.9% for 2000 compared to 68.9% in 1999 due to its inverse relationship with commodity prices.

Royalty Summary

	Year Ended December 31 2000	Year Ended December 31 1999
	($)	($)
Crown Royalties	1,909,226	1,279,406
Indian Oil & Gas Canada Royalties	362,993	–
Freehold Royalties	106,255	72,224
Gross Overriding Royalties	111,426	49,157
	2,489,900	1,400,787
Alberta Royalty Tax Credit (ARTC)	(270,485)	(561,236)
Net Royalties	2,219,415	839,551
Net Royalties per BOE (10:1)	9.86	3.46
Net Royalties per BOE (6:1)	8.54	3.13

Operating Expenses

Operating expenses in calendar 2000 were $2,043,410 ($7.87 per BOE) compared to $1,543,624 ($6.36 per BOE) in fiscal 1999. Operating costs have increased due, in part, to the increased natural gas production which has higher operating costs compared to oil due to third party processing requirements. Major workovers at two wells at Meekwap East Flank, plant turnaround at the Meekwap D-2A Unit, production problems at Epping, Saskatchewan and chemical treatments at Willesden Green where the Company took over as operator effective January 1, 2000 also contributed to abnormally high operating expenses.

Depletion, Depreciation and Amortization

Depletion and depreciation was $1,644,700 for the year ended December 31, 2000, which represents a provision of $6.34 (10:1) per BOE of production. For the year ended December 31, 1999, the Company recorded a depletion and depreciation provision of $1,386,100 ($5.71 per BOE).

General and Administrative

Gross general and administrative costs have increased from $1,435,082 in 1999 to $1,599,608 mainly due to the hiring of additional exploration staff.

	Year Ended December 31 2000 ($)	Year Ended December 31 1999 ($)
Gross General & Administrative	1,599,608	1,435,082
Acquisition, Exploration & Development Costs Capitalized	(416,120)	(300,000)
Overhead Recoveries	(495,819)	(463,033)
Net General & Administrative	687,669	672,049
Per BOE (10:1)	$ 3.05	$ 2.76
Per BOE (6:1)	$ 2.65	$ 2.51

Equity

On May 15, 2000 the Company issued 2,302,196 shares as part of the consideration for the purchase of Auburn Energy Ltd.

Under normal course issuer bids the Company purchased 1,400,000 shares at a cost of $1,004,012.

Acquisitions and Divestitures

TUSK acquired all of the issued and outstanding shares of Auburn Energy Ltd. effective May 15, 2000 under the terms of a plan of arrangement for $3,580,505 cash and the issue of 2,302,196 common shares. The primary asset of Auburn, at the time of the acquisition, was a joint venture agreement with Keyano Pimee Exploration Company Ltd., a company owned by the Saddle Lake and Whitefish Lake First Nations. At the time of the closing, Auburn held a 40% net interest in seven gas wells and had the right to drill on more than 80 sections of additional lands subject to the joint venture arrangements. Subsequent to the closing, Auburn (TUSK) has drilled one gas well in the third quarter and three gas wells in the fourth quarter increasing to 11 the total number of Auburn/Keyano gas wells in the Saddle Lake area. In June, 2000 Auburn formalized an arrangement with the Alexis First Nation expanding the Company's overall exposure to more than 105 sections of First Nations lands.

The Company sold its interest in a Northeast British Columbia Project, including two shut-in gas wells which has not been tied-in, to a third party in the first quarter of 2000 for $1,416,000.

Effective December 31, 2000 the Company sold 6.056% working interest in the Meekwap D-2A Unit and 50% of its interest in the Meekwap East Flank and Meekwap North to a third party for $3.9 million cash.

Capital Expenditures

Cash capital additions for the year ended December 31, 2000 were $6,569,268 compared to $4,486,178 for the year ended December 31, 1999.

	Year Ended December 31 2000 ($)	Year Ended December 31 1999 ($)
Land	1,151,365	494,518
Seismic & Exploration	1,454,085	331,384
Drilling & Completion	3,233,530	3,138,315
Facilities	696,365	490,066
Corporate	33,923	31,895
Total	6,569,268	4,486,178

Liquidity and Capital Resources

TUSK had a working capital deficiency of $2,223,265 at December 31, 2000.

The Company has a financing arrangement with a Canadian financial institution whereby the Company has been provided a $7.6 million revolving production loan. $4,350,000 of the revolving production loan was drawn at December 31, 2000. Subsequent to December 31, 2000, the Company negotiated a revision to the credit facility to a revolving loan in the amount of $9,000,000 with monthly borrowing base reductions of $300,000 to commence May 1, 2001, for four months, then $200,000 per month thereafter.

Change in Accounting for Future Income Taxes

On January 1, 2000, the Company changed its policy on accounting for income taxes to the liability method, prior thereto, the Company followed the deferral method. The new method was applied retroactively without restatement of prior period financial statements. At January 1, 2000, the future income tax liability was increased by $1,065,000, retained earnings was increased by $1,387,000, share capital was increased by $743,000, and property, plant and equipment was increased by $3,195,000. These adjustments were a result of the future tax cost recognition of the impact of the issue of flow-through shares.

Business Risks

The marketability and price of products owned or that may be acquired or discovered by TUSK will be affected by numerous factors beyond the Company's control. TUSK must compete in all aspects of its operations with a number of other corporations that have equal or greater technical or financial resources. The ability of the Company to market its natural gas may depend on its ability to acquire space in pipelines that deliver natural gas to commercial markets. The Company is also subject to market fluctuations in the prices of products, exchange rates, deliverable uncertainties related to the proximity of its reserves to pipelines and processing facilities and extensive government regulation.

Share Trading Information

	2000			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
High ($/share)	0.81	0.85	0.72	0.77
Low ($/share)	0.55	0.55	0.62	0.63
Close ($/share)	0.69	0.75	0.66	0.65
Volume	1,479,744	1,964,994	1,135,602	1,547,557
Value ($)	1,014,708	1,579,498	744,430	1,067,700

Quarterly Data (Unaudited)

A quarterly summary of the key financial results reported in the 12 months ending December 31, 2000 are as follows:

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
	($)	($)	($)	($)
Oil & Gas Revenue, Net of Royalties	2,078,932	1,880,109	1,467,330	1,379,417
Net Income (Loss)	287,204	244,680	155,456	221,252
Net Income (Loss) Per Share	0.02	0.01	0.01	0.02
Cash Flow	1,197,404	935,080	667,256	745,152
Cash Flow Per Share	0.08	0.07	0.04	0.06
Annualized Cash Flow	0.32	0.28	0.16	0.24
BOE's per Day (10:1)	688	668	540	570
BOE's per Day (6:1)	806	792	632	612

Income Tax Pools (Unaudited)

The consolidated income tax pools for the Company and its subsidiaries estimated as of December 31, 2000 are as follows:

	$
Canadian Exploration Expense	3,061,000
Canadian Development Expense	872,000
Canadian Oil & Gas Property Expense	2,409,000
Mining Depletion	30,000
Foreign Exploration and Development	335,000
Undepreciated Capital Costs	1,027,000
Business Losses	4,000
Share Issue Expenses	764,000
	8,502,000

Based on the Company's budgeted capital expenditures and budgeted revenue and expenses, the Company does not expect to be taxable in 2001.

Management's Report

The financial statements are the responsibility of the management of TUSK Energy Inc. They have been prepared in accordance with generally accepted accounting principles, using management's best estimates and judgements, where appropriate.

Management is responsible for the reliability and integrity of the financial statements, the notes to the financial statements, and other financial information contained in this report. In the preparation of these statements, estimates are sometimes necessary because a precise determination of certain assets and liabilities is dependent on future events. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management is also responsible for maintaining a system of internal control designed to provide reasonable assurance that assets are safeguarded and that accounting systems provide timely, accurate and reliable financial information.

The board of directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The board is assisted in exercising its responsibilities through the audit committee of the board, which includes three non-management directors. The audit committee meets periodically with management and the auditors to satisfy approval of the financial statements to the board.

KPMG, the independent auditors appointed by the shareholders, have audited the Company's financial statements in accordance with generally accepted auditing standards and their report follows. The independent auditors have full and unrestricted access to the audit committee to discuss their audit and their related findings as to the integrity of the financial reporting process.

Norman W. Holton
President and Chief Executive Officer
March 22, 2001

Gordon K. Case
Vice President and Chief Financial Officer

Auditors' Report

To the Shareholders of TUSK Energy Inc.

We have audited the consolidated balance sheets of TUSK Energy Inc. as at December 31, 2000 and 1999 and the consolidated statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2000 and 1999 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP
Chartered Accountants
Calgary, Canada
March 22, 2001

Consolidated Balance Sheets

Assets

	December 31 2000	December 31 1999
	($)	($)
Current Assets		
Cash	**17,257**	23,470
Accounts Receivable	**4,635,004**	4,757,213
Properties Sale Proceeds Receivable	**3,900,000**	–
Prepaid Expenses and Deposits	**101,796**	127,770
	8,654,057	4,908,453
Loans to Officers and Directors *(Note 2)*	**832,511**	–
Investment *(Note 3)*	**226,246**	189,650
Deferred Charges *(Note 11)*	**104,000**	156,000
Capital Assets *(Note 5)*	**23,246,144**	11,945,325
	33,062,958	17,199,428

Liabilities and Shareholders' Equity

	December 31 2000	December 31 1999
Current Liabilities		
Accounts Payable and Accrued Liabilities	**6,977,322**	4,953,312
Current Portion of Long-Term Debt *(Note 6)*	**3,900,000**	–
	10,877,322	4,953,312
Long-Term Debt *(Note 6)*	**4,350,000**	3,900,000
Future Site Restoration	**283,062**	252,411
Future Income Taxes *(Note 9)*	**5,912,249**	–
Shareholders' Equity		
Capital Stock *(Note 7)*	**9,991,483**	8,740,455
Retained Earnings (Deficit)	**1,648,842**	(646,750)
	11,640,325	8,093,705
Commitments and Contingencies *(Note 10)*		
Subsequent Events *(Note 13)*		
	33,062,958	17,199,428

Approved on Behalf of the Board:

Norman W. Holton, Director

James E. Lawson, Director

See Accompanying Notes

Consolidated Statements of Operations and Deficit

	For the Year Ended December 31 2000	For the Year Ended December 31 1999
	($)	($)
Revenue		
Oil and Gas Revenues, Net	**6,805,788**	5,086,350
Expenses		
Oil and Gas Operating	**2,043,410**	1,543,624
Interest on Long-Term Debt	**487,087**	277,071
Provisions for Future Site Restorations	**27,600**	42,100
General and Administrative	**687,669**	672,049
Loss on Foreign Exchange Contract Settlement *(Note 11)*	**–**	175,000
Depreciation, Depletion and Amortization	**1,644,700**	1,386,100
	4,890,466	4,095,944
Net Income for the Year Before Future Taxes	**1,915,322**	990,406
Current Income Taxes	**42,730**	–
Future Income Taxes *(Note 9)*	**964,000**	–
	1,006,730	–
Net Income For the Year	**908,592**	990,406
Deficit, Beginning of Year	**(646,750)**	(1,637,156)
Change in Accounting Policy Related to Future Income Taxes *(Note 8)*	**1,387,000**	–
Retained Earnings (Deficit), End of Year	**1,648,842**	(646,750)
Net Income per Share *(Note 12)*		
Basic	**0.06**	0.08
Diluted	**0.06**	0.08

See Accompanying Notes

Consolidated Statements of Cash Flows

	For the Year Ended December 31 2000 ($)	For the Year Ended December 31 1999 ($)
Operating Activities		
Operations:		
Net Income	**908,592**	990,406
Add:		
Items not Requiring Cash		
- Provision for Future Site Restorations	**27,600**	42,100
- Depreciation, Depletion and Amortization	**1,644,700**	1,386,100
- Future Income Taxes	**964,000**	–
Funds from Operations	**3,544,892**	2,418,606
Change in Non-cash Working Capital	**44,661**	(1,380,105)
	3,589,553	1,038,501
Financing Activities		
Issue of Capital Stock	–	3,007,000
Share Issue Costs	**(162,288)**	(331,697)
Repurchase of Common Shares	**(1,004,012)**	(393,750)
Long-Term Debt	**4,350,000**	(438,327)
	3,183,700	1,843,226
Investing Activities		
Oil and Gas Properties	**(6,535,345)**	(4,454,283)
Proceeds on Sales of Oil and Gas Properties	**6,538,591**	475,000
Acquisition of Subsidiary, Net of Cash Acquired	**(3,261,546)**	–
Loans to Officers and Directors	**(832,511)**	–
Investment	**(36,596)**	(8,799)
Furniture and Equipment	**(33,923)**	(31,895)
Deferred Charges	–	(156,000)
Change in Non-Cash Working Capital	**(2,618,136)**	1,311,162
	(6,779,466)	(2,864,815)
Increase in Cash During the Year	**(6,213)**	16,912
Cash: Beginning of Year	**23,470**	6,558
Cash: End of Year	**17,257**	23,470
Funds from Operations per Share *(Note 12)*		
Basic	**0.25**	0.20
Diluted	**0.25**	0.19

See Accompanying Notes

Notes to Consolidated Financial Statements

1. Significant Accounting Policies

(a) Basis of Presentation:

These consolidated financial statements include the accounts of the Company's wholly-owned subsidiaries, Auburn Energy Ltd., New Quebec Platinum Inc., TUSK Oil Corporation and 416600 Alberta Inc.

(b) Oil and Gas Properties:

The Company follows the full cost method of accounting in accordance with the guidelines issued by the Canadian Institute of Chartered Accountants, whereby all costs associated with the exploration for and development of oil and gas reserves are capitalized. All such costs are accumulated in a single cost centre representing the Company's activities. Such costs include land acquisitions, drilling and geological and geophysical expenses related to exploration and development activities. Gains or losses are not recognized upon disposition of oil and gas properties unless crediting the proceeds against accumulated costs would result in a significant change in the rate of depletion.

Costs capitalized in the cost centre, plus a provision for future development costs of proved undeveloped reserves, are depleted using the unit-of-production method, based on estimated proven oil and gas reserves, before royalties, as determined by independent consulting engineers. For purposes of the depletion calculation, oil and gas reserves are converted to a common unit of measure on the basis of their relative heating value. The carrying value of undeveloped properties is excluded in the depletion calculation.

In applying the full cost method, the Company performs a ceiling test which limits the capitalized costs less accumulated depletion and depreciation to an amount equal to the estimated undiscounted value of future net revenues from proven oil and gas reserves, based on year-end prices and costs, and after deducting estimated future general and administrative expenses, future abandonment and site restoration costs, financing costs and income taxes.

The Company periodically reviews the costs associated with undeveloped properties to determine whether the costs will be recoverable. An impairment allowance is made if the results of the review indicate an impairment has occurred.

Estimated future abandonment and site restoration costs are provided for using the unit-of-production method based upon estimated proven reserves. Removal and site restoration expenditures are charged to the accumulated provision account as incurred.

(c) Joint Ventures:

Substantially all of the Company's mining and oil and gas activities are conducted jointly with others. The accounts reflect only the Company's proportionate interest in such activities.

(d) Per Share Amounts:

Per share amounts have been calculated using the weighted average number of common shares outstanding during the year. Diluted per share amounts have been calculated using the treasury stock method.

(e) Measurement Uncertainty:

The amounts recorded for depletion and depreciation of capital assets and the provision for future abandonment and site restoration costs are based on estimates. The ceiling test is based on such factors as estimated proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

(f) Hedging Transactions:

The Company periodically used certain financial instruments to hedge its exposure to commodity price and foreign exchange fluctuations on a portion of its crude oil and natural gas sales. Gains and losses on these transactions are reported as adjustments to revenue when the hedged production is sold.

(g) Income Taxes:

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the current enacted tax rates in effect. The Corporation changed to the liability from the deferral method effective January 1, 2000. (See Note 8)

(h) Stock Options:

The Company has a stock option plan as described in note 7. When stock options are issued the value of the options is not determined or recorded. Any consideration received on the exercise of stock options is credited to share capital.

2. Loans Due from Officers and Directors

The Company has loaned $832,511 to certain officers and directors to purchase common shares of the Company in a market transaction at a price of $0.85 per share. The loans are for a term of three years beginning April 10, 2000, bear interest at a rate of 5% per annum and are secured by the purchased shares. Under the terms of the lending agreement, if the loan becomes due and the sale of the purchased shares is not sufficient to repay the loan and any accrued interest, the borrower must pay the shortfall.

3. Investment

The Company has invested a total of $226,246 in common shares of Loon Energy Inc. ("Loon"), an oil and gas company which is listed on the Canadian Venture Exchange and $300,000, included in accounts receivable, in the form of a demand note payable bearing interest at 1% above the Company's bank's prime lending rate. One officer and director of the Company is an officer and director of Loon and another officer of the Company is a director of Loon.

4. Acquisition of Auburn Energy Ltd.

On May 15, 2000 the Company acquired all of the issued and outstanding shares of Auburn Energy Ltd., a private company engaged in the exploration for and production of natural gas and crude oil in Western Canada.

The acquisition has been accounted for by the purchase method of accounting as follows:

	$
Consideration given	
Cash	3,580,505
Transaction Costs	5,193
Total Cash Consideration	3,585,698
Non-Cash Issue of 2,302,196 Common Shares @ $0.696 per share	1,602,328
	5,188,026
Allocation of Purchase Price	
Capital Assets	10,795,366
Future Income Taxes	(3,995,249)
Future Site Restoration	(3,051)
Net Capital Assets	6,797,066
Working Capital	132,767
Promissory Notes Payable	(1,741,807)
	5,188,026

5. Capital Assets

	December 31, 2000		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	($)	($)	($)
Oil and Gas Properties	35,962,499	12,867,932	23,094,567
Furniture and Equipment	313,050	161,473	151,577
	36,275,549	13,029,405	23,246,144

	December 31, 1999		
	Cost	Accumulated Depletion and Depreciation	Net Book Value
	($)	($)	($)
Oil and Gas Properties	23,165,877	11,315,932	11,849,945
Furniture and Equipment	216,153	120,773	95,380
	23,382,030	11,436,705	11,945,325

During the year administrative overhead expenditures of $416,000 (1999 - $300,000) directly related to the acquisition, exploration and development of petroleum and natural gas reserves have been capitalized. No interest has been capitalized to oil and gas properties in either of the years ended December 31, 2000 or 1999. The depletion calculation has excluded unproved properties of $3,600,000 (1999 - $1,233,000).

As at December 31, 2000, the estimated future site restoration costs to be accrued over the remaining proved reserves are $356,000 (1999 - $390,000).

6. Long-Term Debt

The credit facility is a revolving loan in the amount of $7,600,000 after giving effect to the sale of a portion of the Company's interests in Meekwap effective December 31, 2000 and bears interest at the bank's prime lending rate plus 0.125%. The loan is secured by a $15,000,000 floating charge debenture over the majority of the assets of the Company and a general security agreement covering all present property of the Company. The terms of the credit facility call for monthly principal repayments of $200,000 to commence on March 1, 2001. Subsequent to December 31, 2000, the Company negotiated a revision to the credit facility to a revolving loan in the amount of $9,000,000 with monthly borrowing base reductions of $300,000 to commence May 1, 2001, for four months and then $200,000 per month thereafter.

7. Capital Stock

(a) Authorized:

The Company has authorized capital of:

- an unlimited number of common shares without nominal or par value.
- an unlimited number of first and second preferred shares issuable in series with rights, privileges and conditions to be determined by the Board of Directors.

(b) Issued

Common shares were issued as follows:

	December 31, 2000 Number	December 31, 2000 Amount ($)	December 31, 1999 Number	December 31, 1999 Amount ($)
Balance Beginning of Year	13,697,234	8,740,455	10,466,584	7,662,102
Issued for Cash:				
Exercise of Stock Options	–	–	10,000	7,000
Issued for Purchase of Subsidiary	2,302,196	1,602,328	–	–
Exercise of Special Warrants	–	–	304,750	243,800
Issuance of Common Shares	–	–	400,000	300,000
Issuance of Flow-Through Common Shares	–	–	3,000,000	2,700,000
Less: Tax Effect of Flow-Through Shares	–	–	–	(1,447,000)
Repurchased under Normal Course Issuer Bid	(1,400,000)	(1,004,012)	(484,100)	(393,750)
	14,599,430	9,338,771	13,697,234	9,072,152
Change in Accounting Policy Related to Future Income Taxes *(Note 7)*	–	743,000	–	–
Less: Share Issue Expenses, Net of Tax Effect	–	(90,288)	–	(331,697)
Balance End of Year	14,599,430	9,991,483	13,697,234	8,740,455

(c) Normal Course Issuer Bid:

Under a Normal Course Issuer bid, the Company received approval in January 2000 to purchase up to 1,257,000 of its outstanding common shares until January 25, 2001. A total of 1,212,000 shares at a cost of $855,132 were purchased under the plan in 2000. Subsequent to December 31, 2000 the Company acquired an additional 45,000 shares at a cost of $27,410 prior to the expiry of the issuer bid.

Under a Normal Course Issuer Bid, the Company received approval in January 1999 to purchase up to 940,000 of its outstanding common shares until January 24, 2000. A total of 484,100 shares at a cost of $393,750 were purchased under the plan in 1999 and a total of 188,000 at a cost of $148,880 were purchased for the period January 1, 2000 to January 24, 2000.

The Company received approval in January, 2001 to purchase up to 1,257,000 of its outstanding common shares until January 28, 2002.

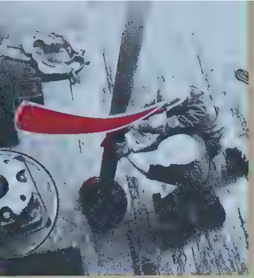
Subsequent to December 31, 2000 the Company has acquired 579,500 common shares at a cost of $406,335 until March 9, 2001 under the issuer bid approved January 2001.

(d) Stock Options

Stock options, entitling the holder to purchase shares from the Company, have been granted to directors, officers and certain employees of the Company. The stock options vest and are exercisable immediately following the grant of the options.

A summary of the status of the Company's stock option plan as of December 31, 2000 and 1999, and changes during the years ending on those dates is presented below.

	2000 Options	2000 Weighted Average Exercise Price ($)	1999 Options	1999 Weighted Average Exercise Price ($)
Outstanding at Beginning of Year	1,459,000	0.98	929,000	1.09
Granted	908,000	0.74	793,000	0.87
Exercised	–	–	(10,000)	0.70
Expired/Cancelled	(372,000)	1.10	(253,000)	1.03
Outstanding and Exercisable at End of Year	1,995,000	0.85	1,459,000	0.98



The following table summarizes information regarding stock options outstanding at December 31, 2000:

Exercise Price ($)	Number Outstanding	Weighted Average Remaining Contractual Life
0.70	668,000	4.5
0.80	360,000	4.6
0.90	663,000	3.5
1.10	220,000	2.0
1.25	84,000	1.0
	1,995,000	3.8

(e) Shareholder Protection Rights Plan:

A Shareholder Protection Rights Plan (the "Rights Plan") was approved at the Annual and Special Shareholders' Meeting June 17, 1998. The Rights Plan utilizes the mechanism of the Permitted Bid to ensure that a person seeking control of the Corporation (an "Acquiring Person") allows shareholders and the Board of Directors sufficient time to evaluate the bid. The purpose of the Permitted Bid (a bid which provides that shares tendered to the bid will not be taken up prior to 60 days following the date of the bid) is to encourage a potential bidder to avoid the dilutive features of the Rights Plan by making a Permitted Bid or by negotiating with the Directors the terms of an offer which is fair to all shareholders.

If a Take-Over Bid does not qualify as a Permitted Bid the Rights Plan provides that shareholders other than the Acquiring Person may purchase shares at a reduced price, thereby diluting the value of the Acquiring Person's shares.

8. Change in Accounting for Future Income Taxes

Effective January 1, 2000, the liability method was adopted; prior thereto, the Company followed the deferral method of accounting for income taxes. The new method was applied retroactively without restatement of prior period financial statements. At January 1, 2000, the future income tax liability was increased by $1,065,000, retained earnings was increased by $1,387,000, share capital was increased by $743,000 and property, plant and equipment was increased by $3,195,000. These adjustments were a result of the future tax cost recognition of the impact of the issue of flow-through shares.

9. Income Taxes

Income tax expense differs from the amount that would be computed by applying the federal and provincial statutory rate of 44.6% to income before income taxes. The reasons for the differences are as follows:

	Year Ended December 31 2000	Year Ended December 31 1999
	($)	($)
Expected Income Tax Expense	854,200	441,700
Non-deductible Crown Charges	850,700	564,500
Alberta Royalty Tax Credit	(120,600)	(250,300)
Resource Allowance	(618,500)	(395,600)
Depletion with No Tax Basis	–	124,200
Capital Taxes	40,000	–
Other	930	9,500
Benefits of Losses	–	(494,000)
Actual Income Tax Expense	1,006,730	–

The components of the future tax liability at December 31, 2000 is as follows:

	Year Ended December 31, 2000
	($)
Capital Assets	(6,571,249)
Share Issue Costs	341,700
Site Restoration	95,700
Foreign Exploration and Development	149,600
	(5,984,249)

10. Commitments and Contingencies

(a) The Company entered into an agreement to lease office space for five years beginning January 1, 1997 for approximately $240,000 per year. A portion of the office space is subleased for approximately $120,000 per year. The sublease can be terminated by either party after six months notice.

(b) The Company has been named in a statement of claim, for an unspecified amount, filed by a joint venture partner against the Company and the previous operator of the Meekwap East Flank Pool alleging that the defendants had failed to account for the joint venture partner's share of revenues from the east flank lands. The amount of the liability, if any, can not be determined at this time.

11. Hedging Transactions

The following hedging contracts were outstanding at December 31, 2000:

(a) The corporation has entered into a swap agreement for 225 barrels per day of oil production for the period from December 1, 1999 to November 30, 2001 at a price of $29.12 Cdn. per barrel. The estimated market value of this contract at December 31, 2000, had it been settled at that time, would result in a payment of $693,192.

(b) The Company entered into a foreign exchange contract which was cancelled August 20, 1999 at a net payment of $331,000. Of that amount, $175,000 of the payment was expensed and the balance of the payment ($156,000) has been deferred and is being amortized over a three year period, beginning January 1, 2000, which represents the original term of the foreign exchange rate arrangement.

12. Per Share Amounts

The Canadian Institute of Chartered Accountants has approved a new standard for the computation, presentation and disclosure of earnings per share. In the fourth quarter of fiscal 2000, the Company retroactively adopted the new standard. Under the new standard, the treasury stock method is used instead of the imputed earnings method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

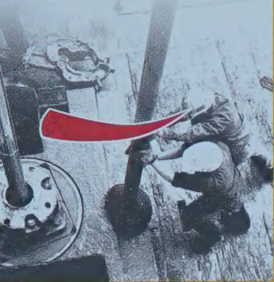
In computing diluted earnings and cash flow from operations per share, 6,670 shares were added to the weighted average number of common shares outstanding during the year December 31, 2000 (1999 - 17,126 shares) for the dilutive effect of employee stock options. No adjustments were required to reported earnings or cash flow from operations in computing diluted per share amounts.

Prior period diluted earnings per share and cash flow from operations per share have been restated for this change. If the imputed earnings method has been used to calculate these amounts, the reported amounts would have been:

	2000	1999
Diluted earnings per common share	0.06	0.08
Diluted cash flow from operations per common share	0.23	0.19

13. Subsequent Event

On March 20, 2001, the Company entered into a letter of intent to acquire all the shares of Spirit Energy Ltd., a private oil and gas company for a total of $2.97 million cash plus payment for net working capital at closing to be determined. In the event that the proposed transaction is not completed by virtue of Spirit completing a similar transaction with a third party, Spirit will pay the Company a break fee of $100,000.



Ten Year Review

	Years Ended December 31						Nine Months Ended December 31	Years Ended March 31		
	2000	1999	1998	1997	1996	1995	1994	1994	1993	1992
Revenue										
Oil & Gas Revenues, Net	**6,805,788**	5,086,350	4,103,157	4,633,819	4,065,606	2,277,728	793,672	685,913	3,151	1,104
Expenses										
Oil & Gas Operating	**2,043,410**	1,543,624	1,373,765	1,376,455	1,104,612	613,938	308,334	267,409	–	–
Interest on Long-Term Debt	**487,087**	277,071	271,490	299,508	283,940	190,695	152,710	22,740	–	–
Provision for Site Restoration	**27,600**	42,100	44,997	63,500	67,800	33,500	7,000	8,000	–	–
General & Administrative	**687,669**	672,049	474,728	406,279	458,860	270,139	239,757	189,846	101,759	56,413
Depreciation and Depletion	**1,644,700**	1,386,100	1,536,100	5,688,700	1,449,180	636,200	507,500	1,248,650	722	208
Loss on Foreign Exchange	–	175,000	–	–	–	–	–	–	–	–
Loss on Disposition of Oil and Gas Property	–	–	–	–	–	–	3,590,401	–	–	–
Property Impairment	–	–	–	73,080	–	–	–	636,432	12,139	130,000
	4,890,466	4,095,944	3,701,080	7,907,522	3,364,392	1,744,472	4,805,702	2,373,077	114,620	186,621
Income Taxes	**1,006,730**	–	–	–	–	–	–	–	–	–
Net Income (Loss)	**908,592**	990,406	402,077	(3,273,703)	701,214	533,256	(4,012,030)	(1,687,164)	(111,469)	(185,517)
Cash Flow from Operations	**3,544,892**	2,418,606	1,983,174	2,551,577	2,218,194	1,202,956	92,871	205,918	(98,608)	(55,309)
Balance Sheet										
Working Capital (Deficiency)	**(2,223,265)**	(44,859)	(430,714)	(149,368)	613,267	305,893	(167,553)	(1,735,206)	(2,386)	27,495
Other Assets	**345,650**	480,851	145,632	–	–	–	–	–	–	–
Capital Assets	**23,246,144**	11,945,325	10,767,247	9,277,403	12,090,657	4,434,993	3,848,830	7,798,110	753,928	207,441
Long-Term Debt	**4,350,000**	3,900,000	4,338,327	4,257,341	5,385,655	1,662,500	1,600,000	660,000	–	–
Future Site Restoration	**283,062**	252,411	210,311	169,800	106,300	38,500	5,000	8,000	–	–
Future Income Taxes	**5,912,249**	–	–	–	–	–	–	–	–	–
Shareholders' Equity	**11,640,325**	8,093,705	6,268,746	4,846,526	7,211,969	3,039,886	2,076,277	5,394,904	751,542	234,936
Per Share Data										
Net Income (Loss) per Share	**0.06**	0.08	0.04	(0.41)	0.14	0.13	(1.10)	(1.40)	(0.20)	(1.10)
Cash Flow per Share	**0.25**	0.20	0.20	0.32	0.44	0.29	0.03	0.18	(0.16)	(0.14)
Production										
Oil (Bopd)	**475**	562	603	554	455	307	153	146	–	–
Gas (Mcfd)	**1,417**	1,036	519	509	910	416	–	–	–	–
Reserves (Proven & Probable)										
Oil (Mbbls)	**2,516**	3,486	1,788	1,516	1,777	1,217	558	832	–	–
Gas (MMcf)	**20,187**	21,801	18,061	1,650	1,323	1,098	1,138	1,029	–	–

Corporate Information

Board of Directors

William E. Code, Q.C.[1][2]
Calgary, Alberta

Norman W. Holton
Calgary, Alberta

James E. Lawson, C.A.[1][2][3]
Calgary, Alberta

John D. Morgan[1][3]
Montreal, Quebec

[1] Audit Committee
[2] Reserve Evaluation Committee
[3] Compensation Committee

Officers

Ed A. Beaman, P.Eng.
Vice President, Production & Engineering

Ian T. Brown, P. Geol.
Vice President, Exploration

Gordon K. Case, C.A.
Vice President and Chief Financial Officer

Norman W. Holton, P.Geol.
President and Chief Executive Officer

Wayne B. Jessee, P. Eng
Vice President, Corporate Development

Brian W. Mainwaring
Secretary

Transfer Agent & Registrar

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Bankers

Canadian Western Bank
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Auditors

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Legal Counsel

Gowling, Lafleur & Henderson
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T2P 4V5

Third Party Engineering

Chapman Petroleum Engineering Ltd.
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Subsidiaries

TUSK Oil Corporation
416600 Alberta Inc.
New Quebec Platinum Inc.
Auburn Energy Ltd.

Stock Exchange

The Toronto Stock Exchange
Trading Symbol: "TKE"

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